Results of High Resolution Seismic Imaging Experiments for Defining Permeable Pathways in Fractured Gas Reservoirs

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Introduction

As part of its Department of Energy (DOE)/Industry cooperative program in oil and gas, Berkeley Lab has an ongoing effort in cooperation with Industry partners to develop equipment, field techniques, and interpretational methods to further the practice of characterizing fractured heterogeneous reservoirs. The goal of this work is to demonstrate the combined use of state-of-the-art technology in fluid flow modeling and geophysical imaging into an interdisciplinary approach for predicting the behavior of heterogeneous fractured gas reservoirs.

The efforts in this program have mainly focused on using seismic methods linked with geologic and reservoir engineering analysis for the detection and characterization of fracture systems in tight gas formations, i.e., where and how to detect the fractures, what are the characteristics of the fractures, and how the fractures interact with the natural stresses, lithology, and their effect on reservoir performance. The project has also integrated advanced reservoir engineering methods for analyzing flow in fractured systems such that reservoir management strategies can be optimized. The work at Berkeley Lab focuses on integrating high resolution seismic imaging, (VSP, crosswell, and single well imaging), geologic information and well test data to invert for flow paths in fractured systems.

Problem Addressed

It is becoming recognized that in order to obtain the necessary characterization for the exploration and production of natural gas from fractured reservoirs much higher resolution of the features likely to affect the transport of gas will be required than is normally achieved in conventional surface seismic reflection used in the exploration and characterization of petroleum and geothermal resources. Because fractures represent a significant mechanical anomaly, seismic methods are being used by a variety of organizations as a means to image and characterize the subsurface. These vary from reflection methods using P-wave solely from the surface, to state-of-the-art borehole multicomponent methods to provide high resolution definition. These methods are being developed to obtain maximum resolution of the features that will possibly affect the transport of fluids.

During the last ten years there has been considerable research in developing and evaluating various seismic techniques for fracture characterization not only for petroleum and gas applications but for mining, geothermal and nuclear waste disposal. An overall objective of this work is to provide a basis for a comprehensive summary of the state-of-the art methods and an evaluation on the relative value of various seismic methods and their ability to provide useful information on fracture properties. A specific objective will be to provide a hierarchy of the utility of various seismic characterization approaches weighted by such factors as cost of data acquisition, processing needs, equipment availability and theoretical support.

Approach

The work is being carried out in a phased approach, with experiments at controlled field sites to understand fundamental mechanisms of seismic wave propagation in fractured environments, then progressing to larger scales at actual industry field sites. Techniques that yield high resolution results are being employed, to examine the scale at which useful information on fluid flow must be obtained. An unique aspect of our work is the link with reservoir engineering studies. The approach is intended to be an integrated one, involving improvements in data acquisition, processing, and interpretation as well as improvements in the fundamental understanding of seismic wave propagation in fractured gas-filled rock. We believe proper integration with the transport modeling is necessary in order to efficiently develop the geophysical methods.

The first phase of this project involved using detailed high resolution, vertical seismic profiling, seismic crosshole, and single well imaging experiments at CONOCO's Newkirk borehole test facility to map fracture characteristics. These data along with geologic and core data were combined with hydrologic data and inverted to define the flow properties of a fractured reservoir rock. The current phase is to take the developed technology and apply to a gas reservoir at the production scale. Experiments to test advanced seismic imaging methodology have been performed at three different sites, all with different scales of application. These sites are the Conoco Test Facility near Newkirk, Oklahoma, The Shell/MIT test facility in Michigan (Antrim Shale/Reef formation) and the Northern Indiana Power Supply Corporation (NIPSCO) gas storage field in Indiana. Data from other areas has also been analyzed to aid in the development of methods and to validate our software.

Current Results

A. Validation of the Effects of Fractures on Seismic Wave Propagation

During the last year experiments were performed at Conoco's Newkirk test facility to validate and confirm previous experiments to map and characterize fracture permeability. In previous experiments at the Conoco test facility high resolution, (1 to 10 kHz) crosswell and single well seismic surveys were performed in a shallow (15 to 35 m), water saturated, fractured limestone sequence. The objective was to develop seismic methodologies for imaging gas-filled fractures in naturally fractured gas reservoirs. Crosswell (1/4 m receiver spacing, 50 to 100 m well separation) surveys utilizing a piezoelectric source and hydrophones were performed before, during and after an air injection that was designed to displace water from a fracture zone to increase the visibility of the fracture zone to seismic imaging and to confirm previous hydrologic data that indicated a preferred pathway. Single well seismic imaging (a piezoelectric source and an eight element hydrophones array at 1/4 m spacing) was also performed before and after the air injection. The previous crosswell results indicated that the air did follow a preferred pathway that was predicted by hydrologic modeling. In addition, single well seismic imaging with vertical CDP gathers also indicated an anomaly in a location consistent with the crosswell and hydrologic inversion results. Upon completion of the field tests a slant well was drilled (GW-6) and cored to confirm the existence and nature of the seismic anomalies. A vertical fracture was intersected almost exactly where the seismic results had predicted.

As part of the validation effort we wanted to perform experiments to test if the fracture intersected was the one responsible for the seismic anomalies observed in previous experiments. We also wanted to duplicate the previous results in a fracture of known dimensions. Shown in Figure 1 is a schematic of the validation experiments. Table 1 is a list of the different experiments performed and the objective of the different tests. Each test had a specific objective which addressed a different hypothesis of the behavior of seismic waves in fractured media. Air was injected into a packed off zone across the fracture. A series of seismic experiments were conducted (Table 1) before, during and after the air injection. To confirm the initial imaging results a crosswell survey was performed across the fracture zone intersected with the drilling with air injected directly into the fracture to determine if this small fracture was responsible for the large seismic anomalies. The initial results were duplicated, indicating that this fracture was responsible for the initial results. When air was injected into the packed off fracture zone the seismic amplitudes across this fracture were severely attenuated, as well as reflected, duplicating the initial results and validating the conclusion that very small gas bearing features can cause significant seismic anomalies. Current work is focusing on processing of the total data set to test fracture wave guide hypothesis and to develop a means to provide a more quantitative measure of fracture properties from seismic data.

The conclusions of this work are:

1. This experiment has shown that relatively small fractures can account for significant fluid flow. Methods such as VSP and surface reflection may provide clues to general fracture directions and anisotropy but to accurately locate and characterize such features is a

difficult task and requires high resolution subsurface methods. Using standard processing techniques, fracture zones were located which could be detected, but not located, by other means. This was accomplished by utilizing high frequency energy in a combination of crosswell and single well approaches.

2. From a rock physics point of view, we have shown that replacement of water with a gas (in this case air) produces large changes in the P-wave signal, even in such small features as a fracture with a width on the order of a millimeter. This is significant because although our wave lengths were on the order of one half to one meter, we still "saw" the fracture. This lends field evidence support for the displacement discontinuity theories that predict such effects, (Schoenberg, 1980, Pyrak-Nolte et. al, 1990a, 1990b).

B. Large Scale Mapping of Fracture Characteristics

Experiments to test advanced seismic imaging methodology have been performed at two larger scale sites the Shell/MIT test facility in Michigan (Antrim Shale/Reef formation) and the Northern Indiana Power Supply Corporation (NIPSCO) gas storage field in Indiana. The Antrim experiment was designed to determine if single well imaging would be successful in imaging a reef formation away from the well. This was a prototype experiment which proved successful in testing the single well methodology and equipment. Data from this experiment was processed to determine if single well methods could detect features away from the well. Initial results indicate that success in this approach.

The NIPSCO site is a fractured sandstone/shale sequence in which depleted gas reservoirs are being used to store gas. A series of 2-D seismic lines using P-waves have been run over this area. The NIPSO experiment was designed to test the seismic methods and theory developed at the Conoco site. Multi-component, multi-offset Vertical Seismic Profiling (VSP) is being used in a time lapse approach at this site to define fracture characteristics and infer the location of the permeable pathways. The objective of this work is shown in Figure 2. The work at the Conoco Newkirk site as well as other sites have indicated that gas filled fractures will be more visible than water filled fractures. In addition the general nature and direction of fracturing can be inferred from looking at the anisotropy in the two different shear waves. An important component of the work is to compare the resolution in the surface work to the results from the VSP, i.e., in a sense calibrate the sensitivity (or lack of it) of the surface methods. The NIPSCO work is a 4-D experiment in which a "before and after" set of measurements are being made in the gas storage field as the field is filled and depleted with gas. The lay out of the experiment is shown in Figure 3. The first field measurements were performed in December of 1996 when the gas storage reservoir was at its maximum pressure. The next set will be made in April of 1997 when the pressure is at the minimum. The hypothesis tested is that when the pressure is at a minimum water will displace gas, when the pressure is at a maximum the gas will displace the water, thus providing a good seismic difference in the signals, allowing one to infer where the permeable pathways exist. Current work is focusing on processing of the data from this field experiment and preparing for the next stage of field work of the "after" imaging when the gas reservoir will be depleted.

Experiment Specifications:

Well 46

- 970 ft to 578 ft at 8ft intervals, P, S1 and S2 sources at zero offset (well pad).

Well 157

- Run 1 : 1088 ft to 296 ft at 8 ft intervals, P, S1 and S2 sources at well pad, P2 source at site E1.

- Run 2 : 1088 ft to 696 ft at 8 ft intervals, P source at site S1, S1 and S2 sources at site E1.

- Run 3 : 1088 ft to 696 ft at 8 ft intervals, P, S1 and S2 sources at site E2.

- Run 4 : 1088 ft to 696 ft at 8 ft intervals, P, S1 and S2 sources at site N2.

- Run 5: 1016 ft to 984 ft at 8 ft intervals, P and S2 sources East walkaway at 50 ft intervals from about 200 ft to 1550 ft.

- Run 6: 1088 ft to 696 ft at 8 ft intervals, P source at site S2 (2740 ft offset).

The VSP data resulted in over 600 Mbytes of data, witn about 10,000 seismograms. The vibroseis data used a 12 to 99 Hz sweep, 12 s long with a 3 second listen time. The sample rate was 1 ms.

Processing Flow:

1) Convert data from field formatted data tapes.
2) Edit and stack uncorrelated traces.
3) Correlate traces and sort by source type.
4) Use P-wave arrival to calculate 3 component geophone rotation angles.
5) Rotate each source type data set into vertical, horizontal in-line, and horizontal cross-line.
6) For zero offset, use S-wave arrivals to measure s-wave splitting and calculate anisotropy axis of symmetry to estimate fracture orientation.
7) Pick arrival times, calculate P and S-wave velocities and Poisson's ratio.
8) Further data analysis depending of data sets, including: reflection analysis, particle motion analysis, and amplitude vs offset analysis.

The data currently processed is Well 46, Well 157 Run 1 and Well 157 Run 2.

The processing of well 46 data set was limited because of background noise due to gas bubbles in the well and rotation error from near vertical P-wave propagation (in-field access restrictions prohibited using an offset P-wave source location). The data set has not yet been analyzed beyond step 5 because of these limitations. The well 157 data set has had a more thorough processing, although the results shown here should still be considered preliminary and subject to change.

Preliminary Results:

Figure 4 shows the two orthogonal S-wave modes (S1 in-line and S2 cross-line) which were used for shear-wave splitting analysis (i.e. picking s-wave arrivals). As can be seen there is a difference in the arrival times between the two shear waves, indicating anisotropy, presumably caused by the fracturing. Figure 5 shows the P and S-wave average velocity from time picks. Figure 6 shows the S1 and S2 (SV and SH) interval velocity (80 ft interval). Figure 7 shows the interval Poisson's ratio (for 80 ft interval). Figure 8 shows the S-wave splitting (time difference between S1 and S2). Note that the splitting appears to decrease with depth. This is opposite to a medium with consistent fracture orientation. Figure 9 shows the estimated anisotropy axis (and inferred fractured orientation). The plot is from East (0 degrees) to West (180 degrees). Note that the S-waves sources were aligned approximately N-S and E-W, so an orientation of North in Figure 9 would mean no apparent anisotropy. This would be an indication that the VSP did not "see" any fractures, possibly because of the long wavelength. However, the data within the Trenton formation (below about 1000 ft) does seem to be 70 to 75 degrees North of East. This is not inconsistent with results at the Conoco test facility. It was difficult to "see" anything except general anisotropy asociated with the fractures with very long wave length information. However, as the the fractures are changed, i.e. filled with fluid we hope to detect a change in anisotropy in the sections where the fluid invades.

Reservoir Engineering Studies

A fundamental problem in gas field management is the determination of spatial variations in reservoir permeability. While information on permeability variations at a particular well site are often available, this information is difficult to extrapolate between wells. An important complement to such well site measurements are dynamic data, observations of fluid flow variations induced by production. Unfortunately, data which can currently be utilized by existing inversion techniques such as well interference data and tracer data are not routinely gathered in a systematic fashion. One type of data which is gathered at all reservoirs are the relative proportions of fluids and gases produced by each well, such as oil, water, and gas. To date it has been difficult to extract permeability information directly from such dynamic production data. However, in this work we are developing inversion techniques which enables us to infer permeability variations between wells using field production data.

In the example given we shall use water-cut (the ratio of water to water plus oil) to estimate lateral variations in permeability, however, any two phases can be used. The inversion approach is based upon a streamline simulator which efficiently estimates water-cut at each producer. A conjugate gradient algorithm is used to minimize the misfit between water-cut calculated from a model of permeability variation and the observed water-cut. The streamline approach to simulation has been described in Data-Gupta and King (1995) and will not be discussed here. The use of the streamline simulator and a simulated annealing algorithm to infer permeability variations was presented in Vasco et al. (1996) and applied to synthetic water-cut data and water-cut measurements from a single 5-spot.

Here we minimize the misfit to the production data using a conjugate gradient algorithm. The fundamental quantity to be minimized is the misfit between the observed water-cut and the water-cut predicted by the permeability model(**k**), the water-cut residual. For *N* production wells there will be *N* water-cut residuals. A measure of total water-cut misfit, over a suite of producing wells, is provided by the least-squares criterion, the sum of the squares of the *N* residuals $r_i, i=1,2,...,N$

$$S(k) = \sum^{N} \left[W_0 - W_c(k)\right]^2$$

where W_0 is the observed water-cut and $W_c(\mathbf{k})$ is the calculated water-cut which is a function of the permeability distribution, denoted by the vector (**k**).

The conjugate gradient algorithm is a general descent technique which uses the gradient of the misfit function to determine adjustments to **k** which will improve the fit to the water-cut observations (Fletcher and Reeves 1964, Parker 1994). A differencing technique is used to calculate the gradient elements so our approach only requires the prediction of water-cut given a permeability distribution. There is non-uniqueness in the inversion procedure in that many permeability distributions may lead to the same set of water-cut predictions (Backus and Gilbert 1968, Vasco et al. 1997). The produces instability in the inversion routine and makes it sensitive to the initial estimate of permeability. In order to stabilize the algorithm we incorporate a penalty term which measures the roughness of a given model. That is, rather than just minimizing the above misfit term $S(\mathbf{k})$ we minimize the sum $S(\mathbf{k}) + P(\mathbf{k})$ where the additional term represents a measure of the spatial continuity of the permeability distribution, the spatial derivative of the permeability field,

$$P(k) = |\nabla k|^2$$

Thus, we are estimating the smoothest model which fits the data. The details of the penalized misfit approach may be found in Vasco et al. (1996).

Field Example

The North Robertson Unit is a heterogeneous, low permeability carbonate reservoir in the Permian Basin of West Texas (Doublet et al. 1995). The producing horizons are the Glorieta and Clearfork Formations between depths of 5,870-7,440 feet. As with the majority of such reservoirs there are production problems such as lack of reservoir continuity, low waterflood sweep efficiency, early water breakthrough, and water channeling. Reservoir conditions are dominated by variations in pore geometry and rocks containing similar total porosity may have significantly different permeability. The non-reservoir rock types are relatively impermeable and form vertical flow barriers contributing to reservoir heterogeneity and compartmentalization. Estimating the distribution of such barriers is essential for the success of secondary and tertiary oil recovery. The current waterflood utilized a 40-acre five-spot pattern type with a 20-acre nominal well spacing (Figure 10).

We are initially using data from sections 326 and 327 of the field and examining 820 days of production/injection history. The injection and production histories for these sections are shown in Figures 11a and 11b for 3405 days. We chose to consider the first 820 days of production/ injection data because after 900 days a number of new injectors were added (Figure 11a) and we wished to avoid the additional complications associated with the changing flow pattern. The injection and production data we are modeling is shown in Figure 12a and 12b respectively. Note the changing rate at some injectors as well as the significant difference in water break-through times at the producers. The measurements in Figure 12b form our basic data set. As is perhaps typical with water-cut observations, the data are quite noisy and interference between wells is visible.

Attempts to model the reservoir using a single layer could not reproduce the observed arrival of the water. Therefore, we represent the heterogeneity in the producing interval using a dual-porosity model. Specifically, a simple three-layer model represents the variations in permeability within the Glorieta and Clearfork Formations. The top layer, with a higher mean permeability of 500 milli-darcies models the presence of fractures within the carbonate reservoir. A middle layer was characterized by an intermediate permeability of 50 milli-darcies. The bottom layer contains a low mean permeability of 5 milli-darcies, representing the formation matrix. Each layer was subdivided into a 50 by 25 grid of blocks or cells and the permeability of each cell represented the unknowns. The conjugate gradient algorithm was executed on a Pentium PC and ran for 18 iterations, reducing the misfit to the water-cut data by approximately half. The inversion took 3 days on the pentium with most time occupied in calculating the gradient elements. The resulting permeability variation for the high permeability top layer are shown in Figure 13. Broad variations in permeability are visable with generally higher values in the south-west and north-central portions of the reservoir.

It is now possible to use production data such as water-cut to infer permeability variations within a reservoir. Our initial results are encouraging and indicate that water-cut data do constrain the large scale variations of reservoir permeability. The inversion of production data can require a significant amount of computation but is feasible because of the efficiency of the streamline simulator. Using crude parallelism such as estimating the gradient components upon a number of workstations can provide a large speed-up with little additional programming. We are currently implementing a Parallel Virtual Machine (PVM) version of the code to accomplish this.

Applications and Benefits

A fundamental problem in gas field management is the determination of spatial variations in reservoir permeability. While information on permeability variations at a particular well site are often available, static data, this information is difficult to extrapolate between wells. An important complement to such well site measurements are dynamic data, observations of fluid flow variations induced by production and information on the physical properties between wells, i.e. geophysical data. Unfortunately, data which can currently be utilized by existing inversion techniques such as well interference data and tracer data are not routinely gathered in a systematic fashion. One is forced to use indirect measurements of flow and transport properties. In this work we examine the scale at which one must characterize the subsurface in order to correctly predict fluid flow. To date it has been difficult to extract permeability information directly from such dynamic production data. However, in this work we are developing inversion techniques which enables us to infer permeability variations between wells using field production data. The anticipated product of this work will be improved interpretational and predictive methods which will be used by the petroleum industry to enhance the recovery from existing and new reservoirs. This effort will also provide feedback such that geophysical methods can be improved and refined in an optimal fashion.

Future Activities

Future work will pursue field and laboratory scale experiments to explain why and how such small features cause such large seismic anomalies, using S-waves as well as P-waves. Just as importantly, we will also take the high frequency crosshole and single well methods to larger scales with surveys in production environments. In the NIPSCO experiment we will perform the "after" imaging experiments when the gas has been depleted to determine if we can map the zones of gas transport. We feel that only in this joint basic/applied approach can we make true progress in developing useful methods for characterizing fractured reservoirs.

Acknowledgments

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Testing Sequence: (receiver offset: Δz=0.125 m = 4.6 inches)

1. Baseline Fracture Interface Wave (FIW) Survey: 5->6 & 5->2
   (purpose: to establish if we can observe a FIW before fracture is perturbed in step 2)
   - Put source in well 5.
   - Put geophone strings in wells 6 & 2.
   - Collect zero-offset data from top to bottom of Ft. Riley: 5->6 & 5->2.
   - Pull geophone string from well 6 and lower 3-component receiver.
   - Collect zero-offset 3-component data in well 6 from top of Ft. Riley to bottom of well.

2. Monitor Transmission/Reflection During Air Injection: 3->1 & 3->4
   (purpose: to establish that well 6 fracture is same fracture that connects wells 5 & 2)
   - Pack off fracture in well 6.
   - Fix source in well 3 at depth=23 m (depth of max. single well reflection).
   - Fix geophone strings#1 & #2 in wells 1 and 3 at depth=23 m.
   - Monitor changes in transmitted and reflected waves during air injection (@40 psi).
   - Stop air injection when amplitudes of transmitted & reflected waves stabilize.

3. Monitor Fracture Interface Wave During Air Injection: 5->6 & 5->2
   (purpose: amplitude and travel time of FIW should increase as air fills fracture)
   - Release air pressure in well 6; allow several hours for fracture to refill with water.
   - Fix source in well 5 at center of Ft. Riley (depth=23 m).
   - Fix geophone string#1 in well 2 centered at depth of 23 m.
   - Fix geophone string#2 above packer in well 6.
   - Inject air into well 6 (@40 psi; check for air bubbles in wells 2,3,&5).
   - Monitor 5->2 & 5->6 during air injection.
   - Stop air injection when FIW amplitude stabilizes.

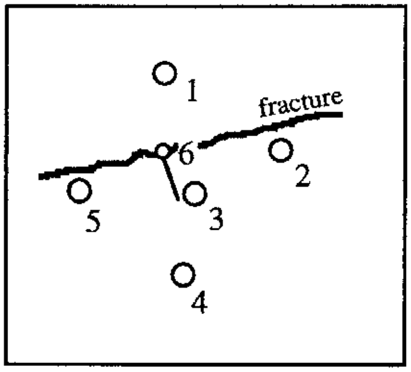
4. "After-Injection" Fracture Interface Wave Survey: 5->6 & 5->2
   (purpose: follow up of step 1 after air injection)
   - Collect zero-offset 5->2 geophone data from top to bottom of Ft. Riley.
   - Pull packer from well 6.
   - Collect zero-offset 5->6 3-component data from top of Ft. Riley to bottom of well.
   - Pull 3-component receiver from well 6 and drop geophone string.
   - Collect zero-offset 5->6 geophone data from top of Ft. Riley to bottom of well.

5. Establish Interwell Hydraulic Connections Between Wells 6->2 & 6->5
   (purpose: to establish "ground truth" hydraulic connectivity between 6->2 & 6->5; do this last in case we accidentally hydrofracture the fracture)
   - Allow several hours for fracture to refill with water.
   - Measure baseline water levels in all wells.
   - Pack-off well 6 and pump water (@40 psi).
   - Measure water level changes in all wells.

Table 1 Experiments and objectives for Conoco test site fracture detection validation test.

Conoco Fracture Interface Wave Air Injection Test 10-96

Plan View of Test Site

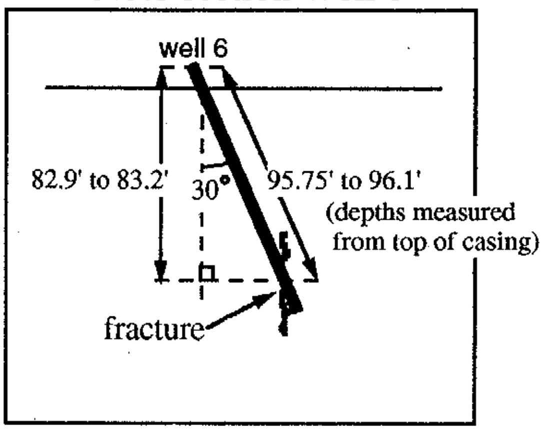


- Ground elevation at wells:
  gw1=77', gw2=72', gw3=78', gw4=82', gw5=84'
  (note: John used gw3 as references in his figures)

- Average velocities of Ft. Riley limestone:
  vp=4000 m/s; vs=2200 m/s

- Regional dip:
  <1 deg. west-southwest

Cross-section Well 6



Fracture Interface Wave Test: 5->2 & 5->6

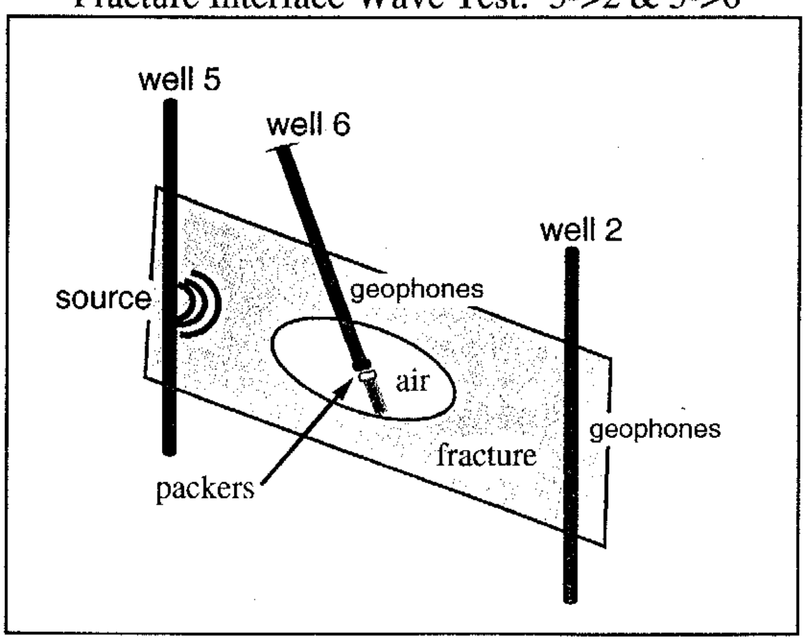
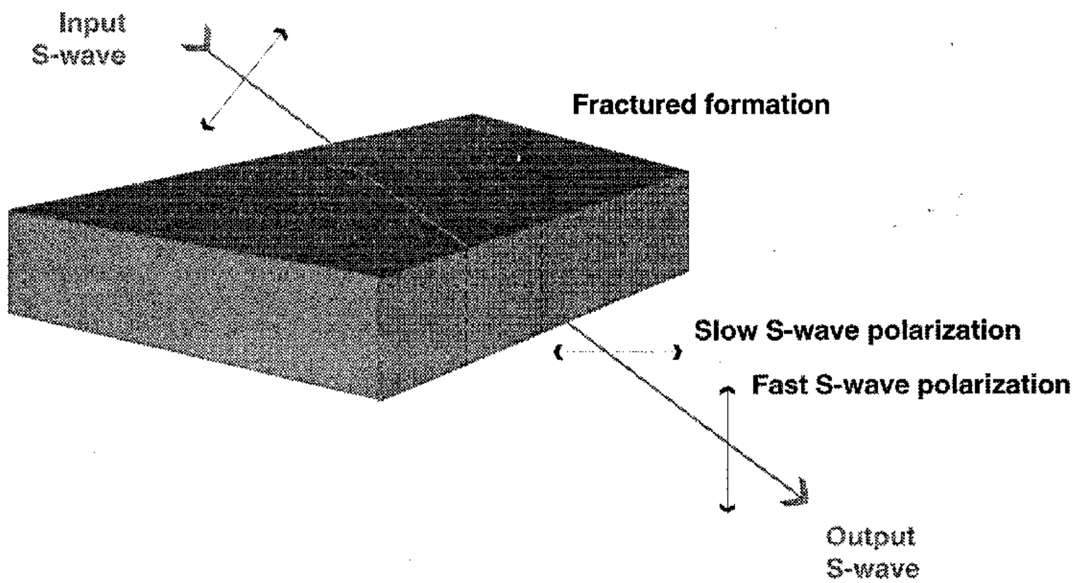


Figure 1 Schematic view of validation experiments at the Conoco test site. Plan view (top) shows well locations (1 through 6) and approximate fracture location. Well 6 cross-section (middle figure) is shown with fracture intersection. The bottom figure shows the fracture interface wave test layout.

NIPSCO VSP Experiment

Objective 1: Determine fracture orientation from s-wave splitting.



Objective 2: Estimate fracture location from winter/summer changes in P & S wave attributes

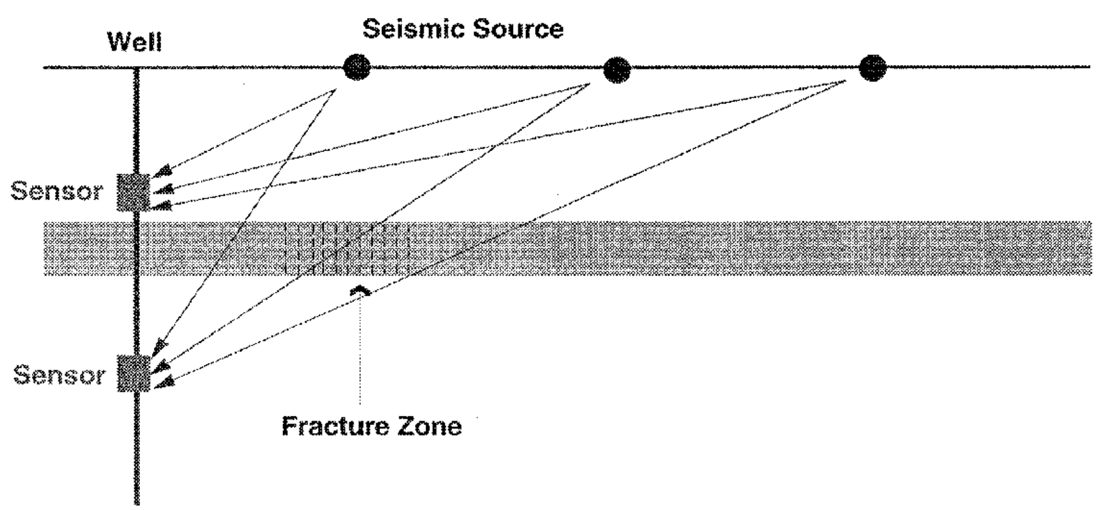


Figure 2 Major objectives of NIPSCO 9-component VSP experiment.

NIPSCO VSP Source Locations

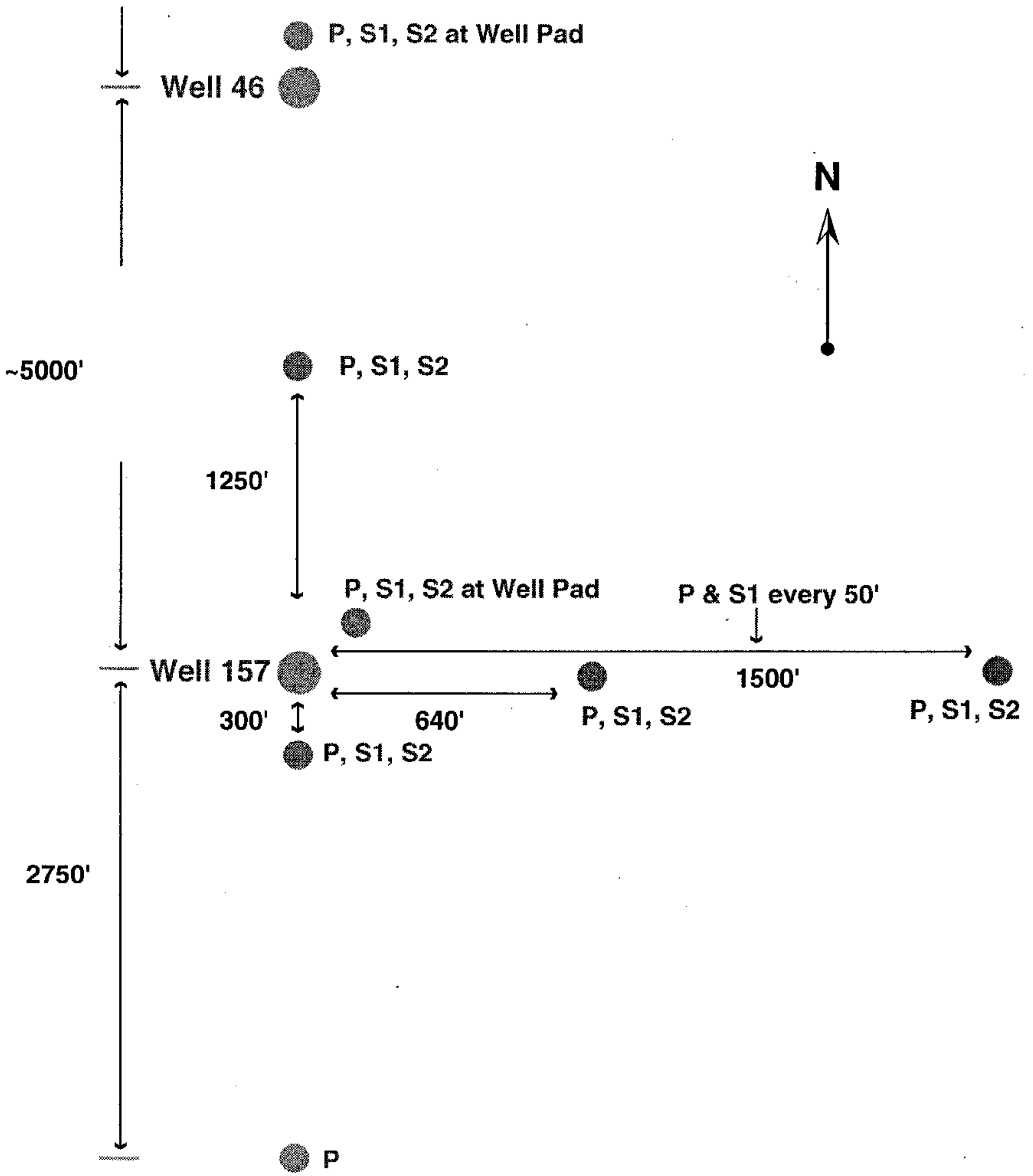


Figure 3 Experimental layout of NIPSCO 9-component VSP experiment.

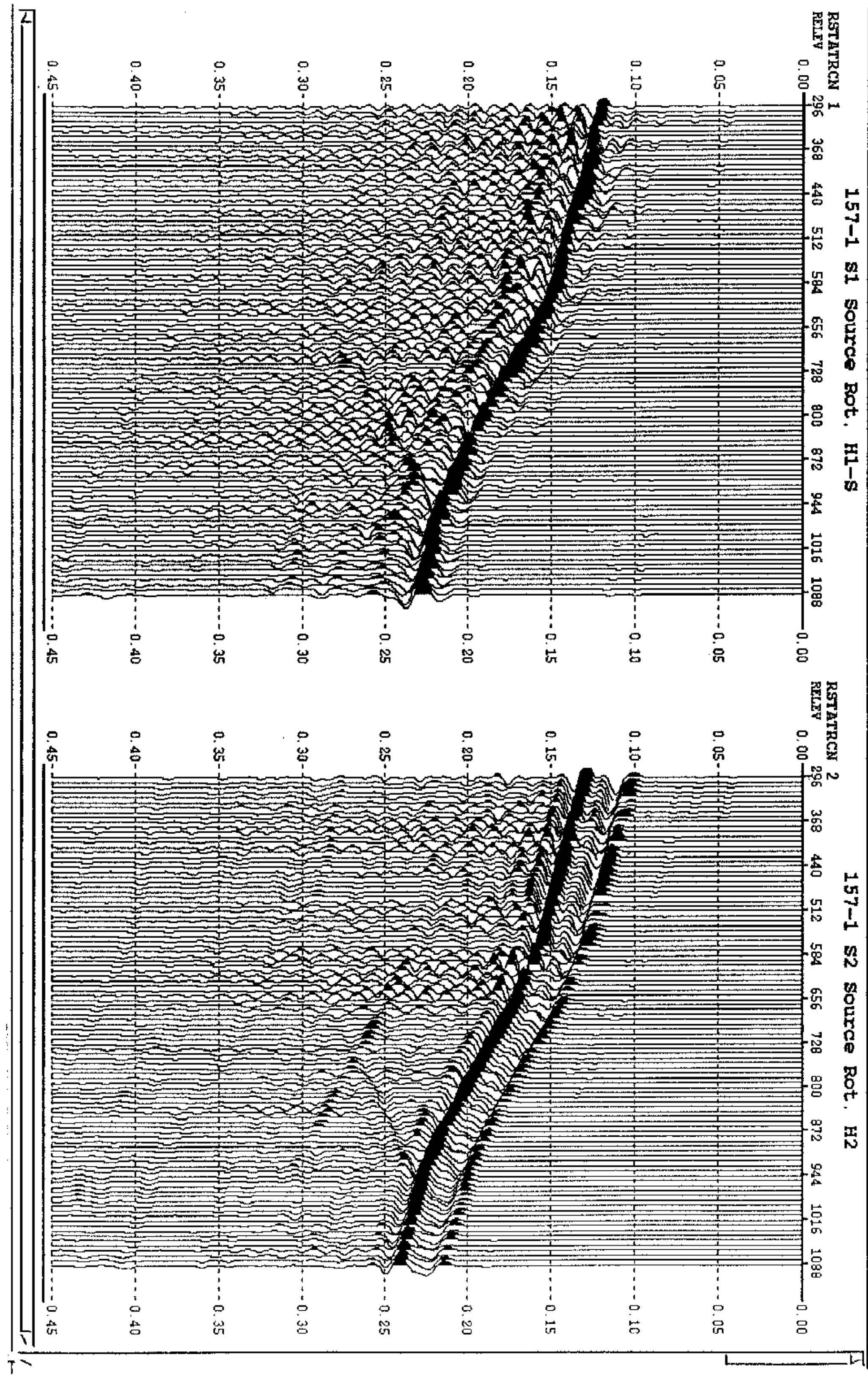


Figure 4 Seismograms from orthogonal S-wave experiment at NIPSCO Well 157. The left side data set is in-line horizontal oriented sensors recording an in-line oriented S-wave source over the depth range 296 ft to 1088 ft. The right side data set is cross-line horizontal oriented sensors recording a cross-line oriented S-wave source over the same depth range. These data sets are used for estimating shear wave anisotropy which is often controlled by subsurface fracturing.

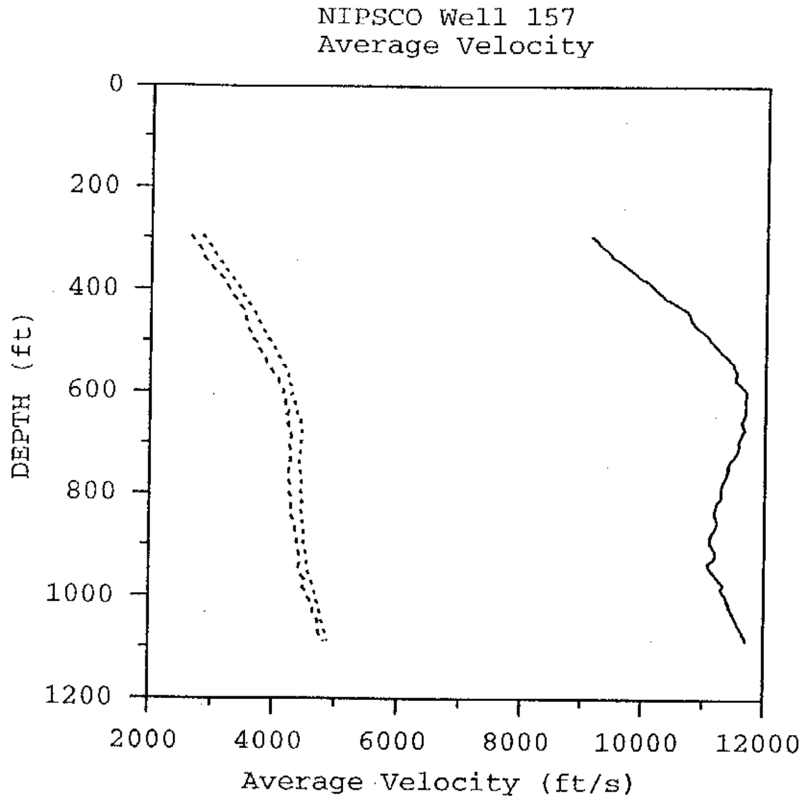


Figure 5 P- and S-wave average velocity from VSP in NIPSCO Well 157.

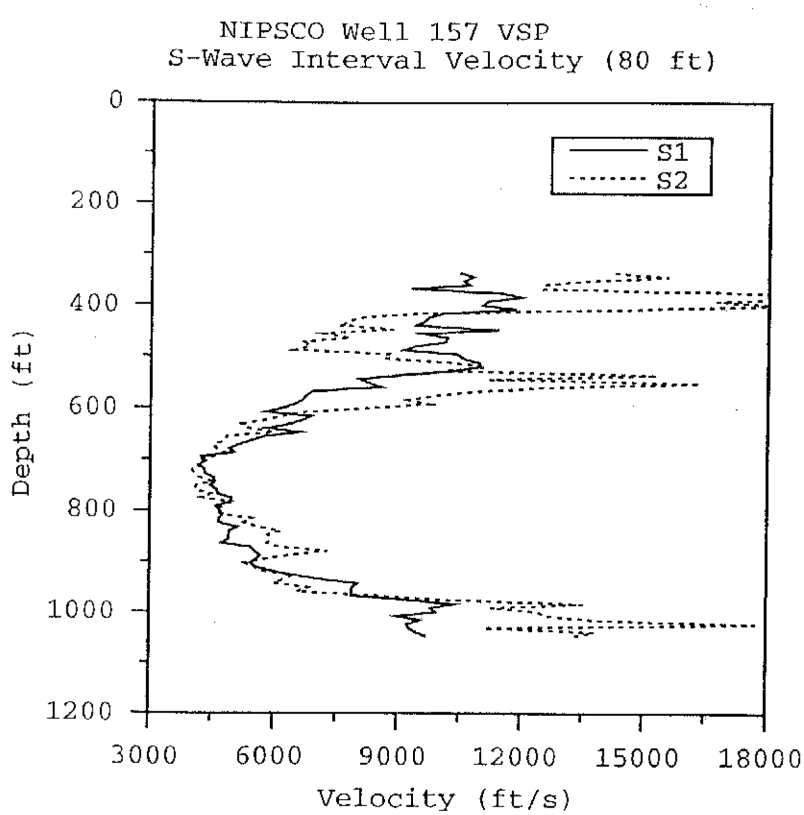


Figure 6 S-wave interval velocity from VSP in NIPSCO Well 157.

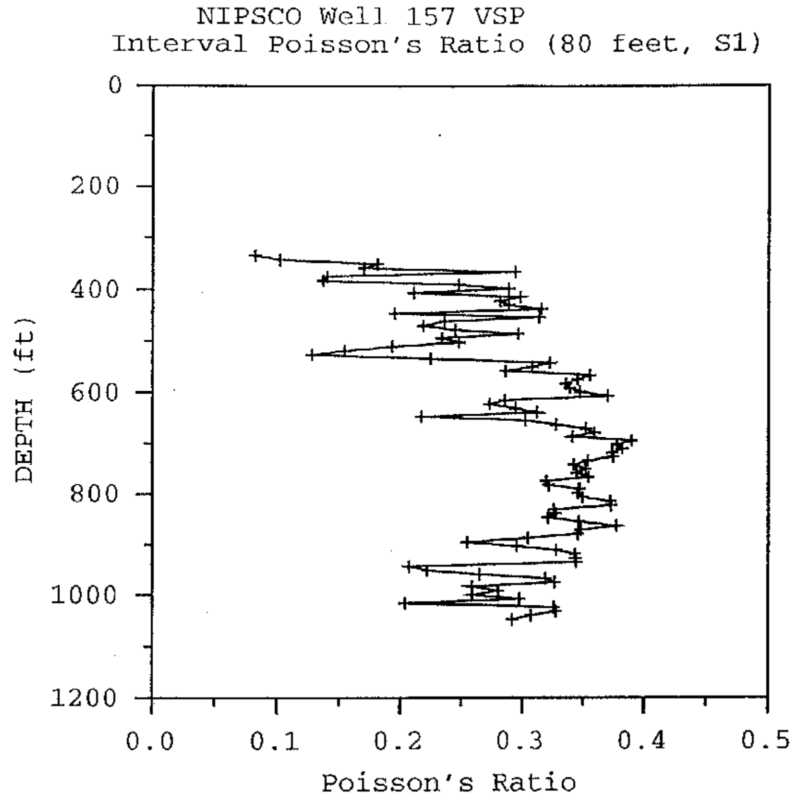


Figure 7 Interval Poisson's ratio, calculated from P- and S-wave interval velocities in NIPSCO Well 157. The averaging interval is 80 ft.

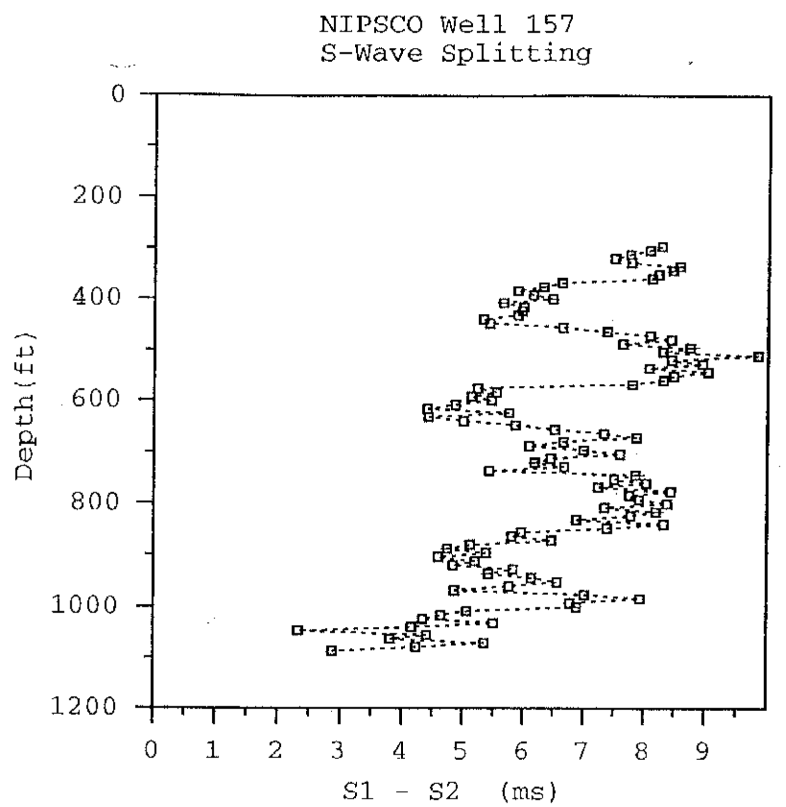


Figure 8 S-wave splitting estimated from data in Figure 4.

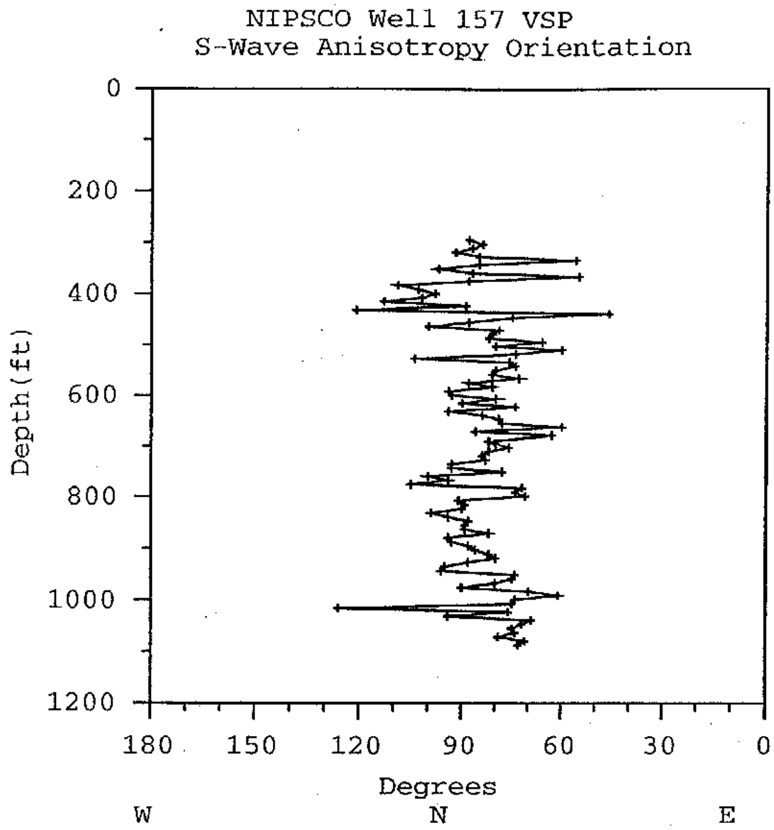


Figure 9 Estimated azimuth of S-wave anisotropy axis (and inferred fracture orientation) from S-wave VSP data at NIPSCO well 157. West is 180 degrees, North is 90 degrees and East is 0 degrees.

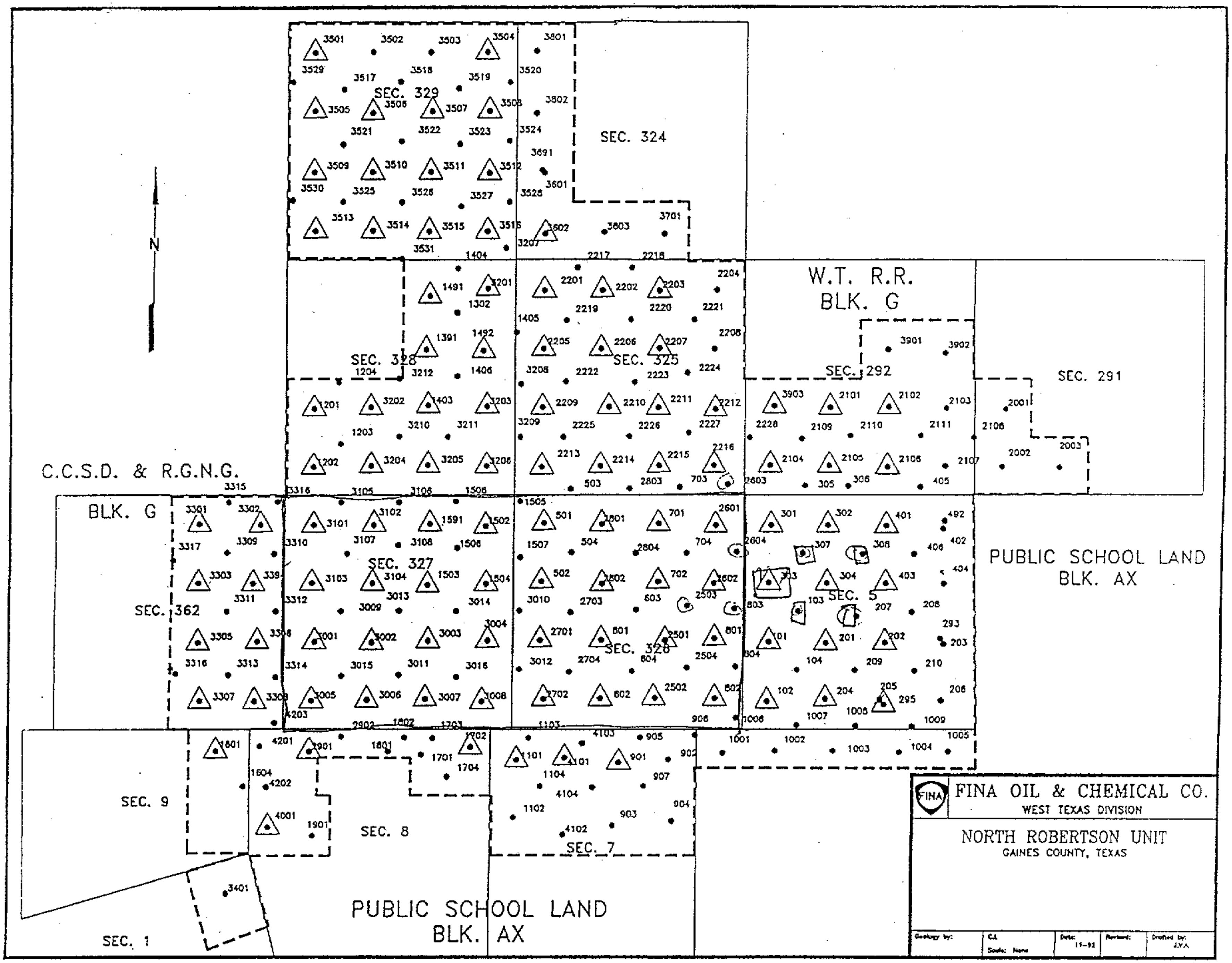


Figure 10 Layout map of well sites in the North Robertson Unit. Circled wells show the five-spot pattern.

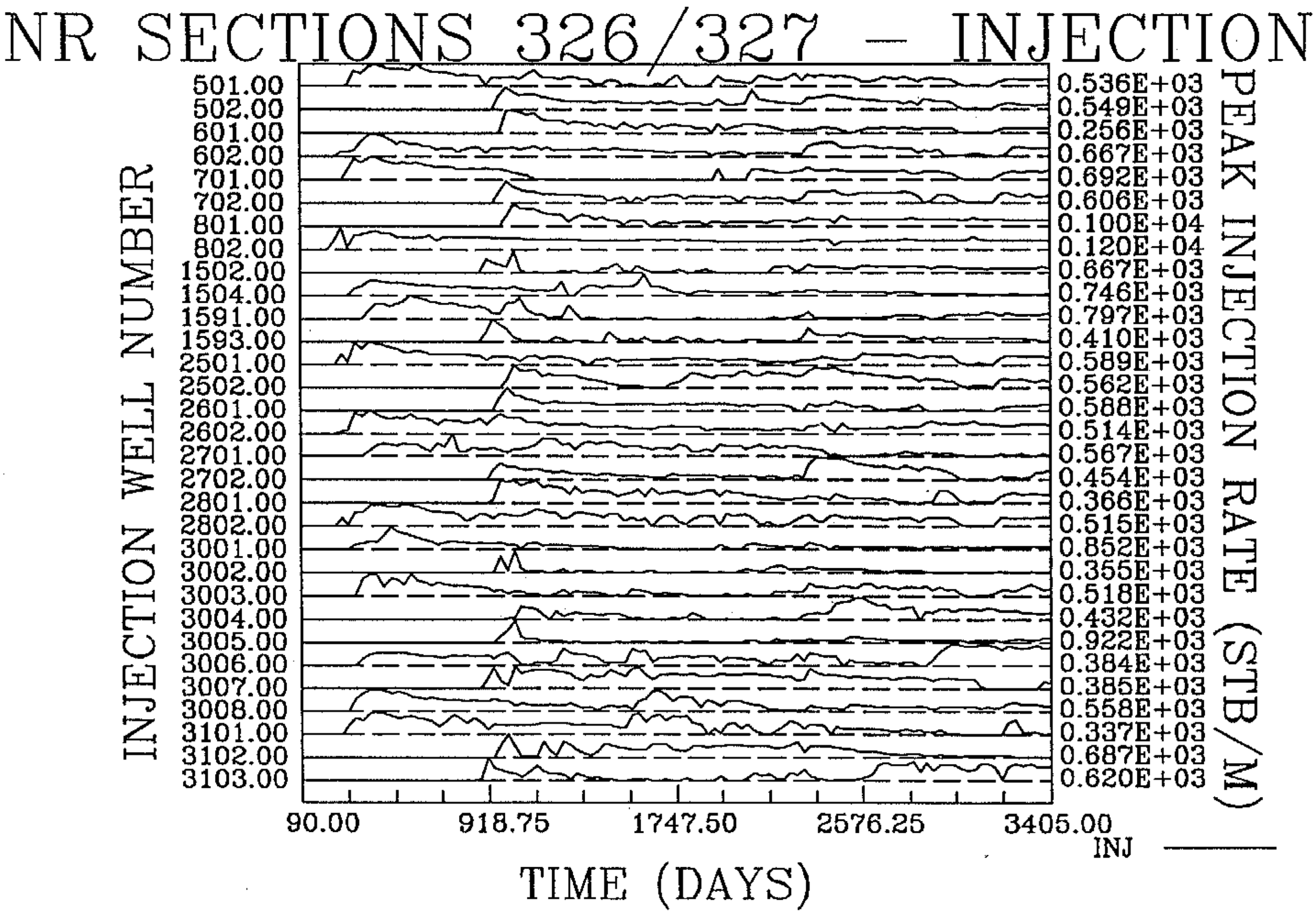


Figure 11a Complete injection data used for North Robertson waterflood.

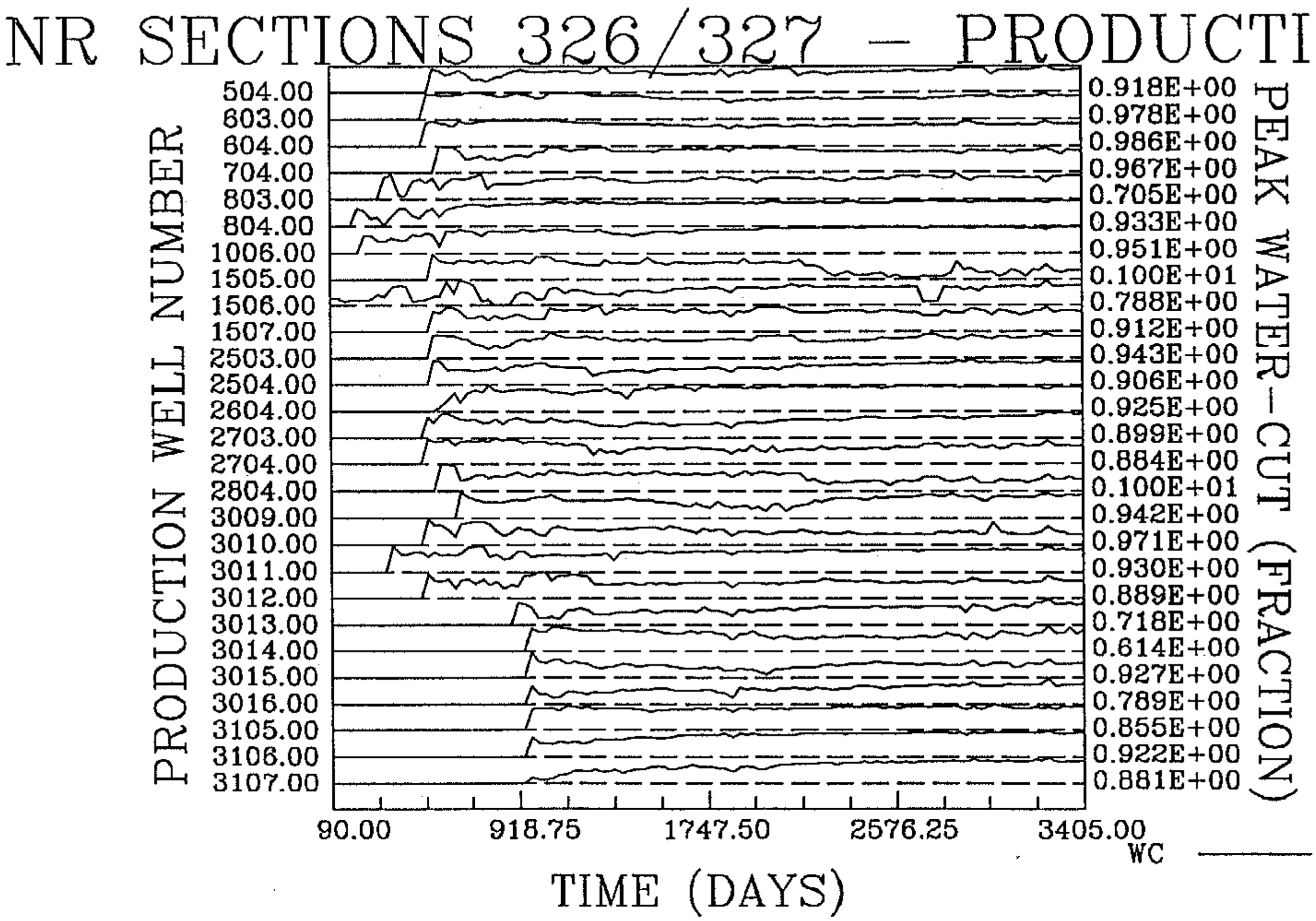


Figure 11b Complete production data used for North Robertson waterflood.

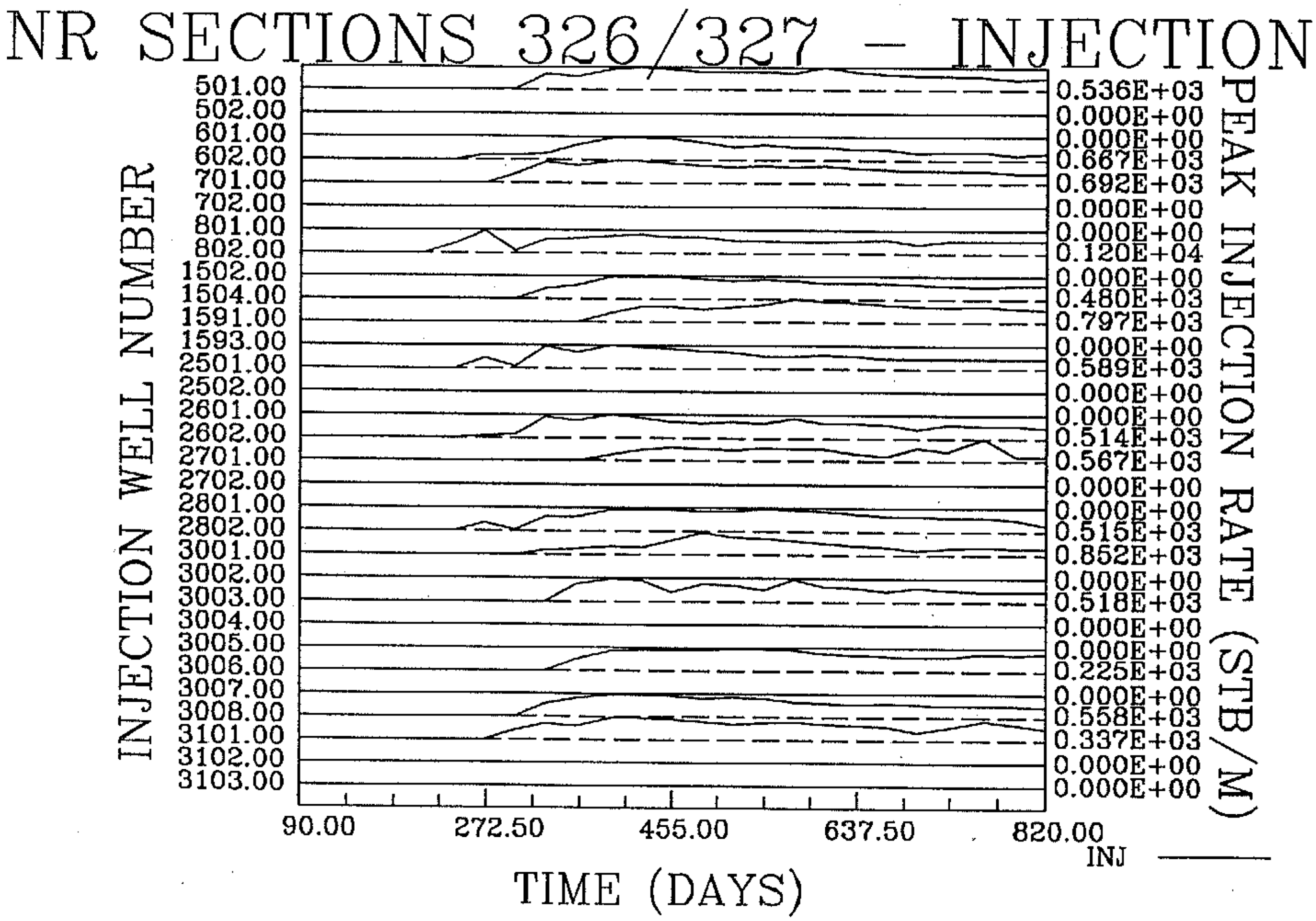


Figure 12a Analyzed segment of injection data for North Robertson waterflood.

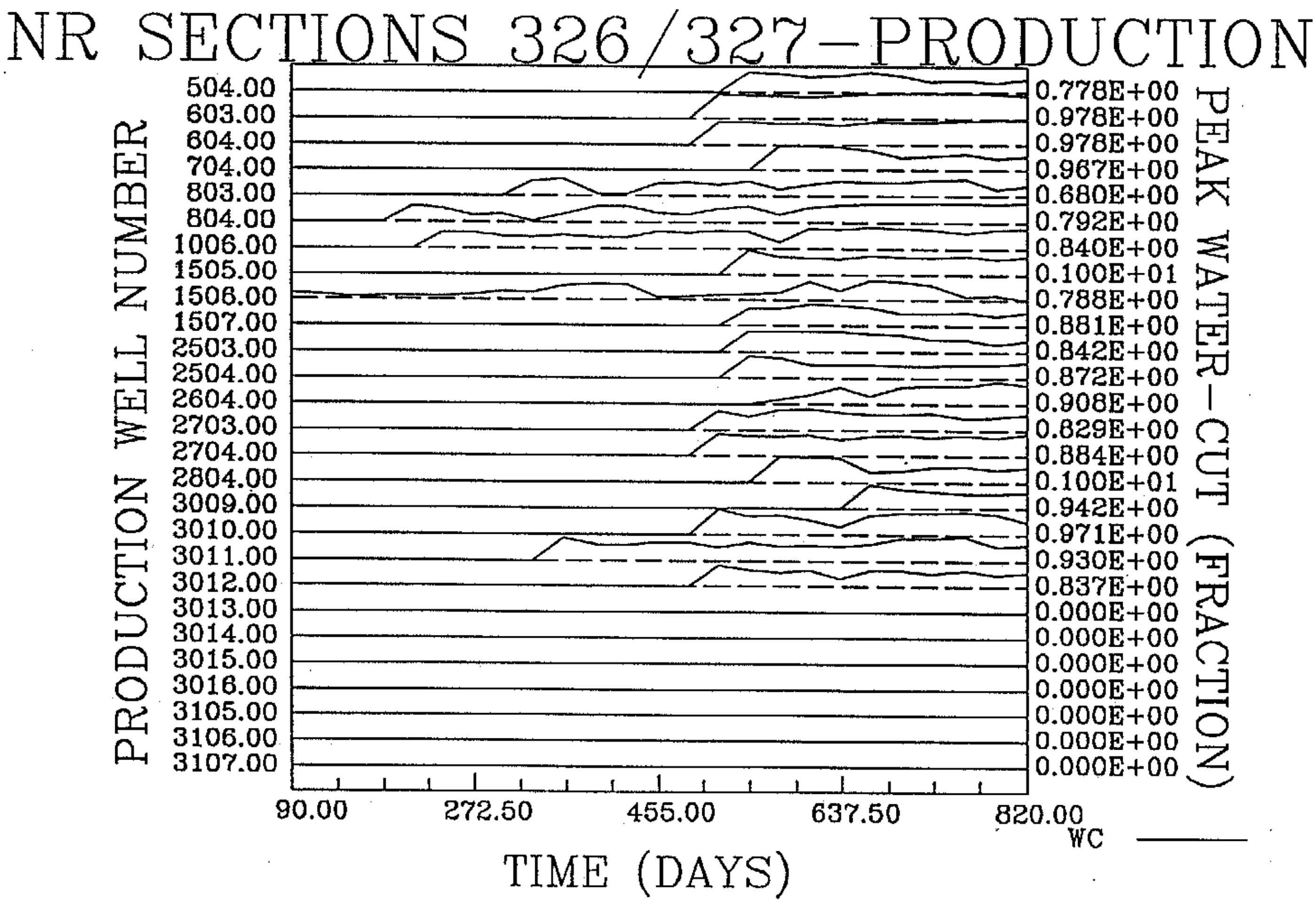


Figure 12b Analyzed segment of production data for North Robertson waterflood.

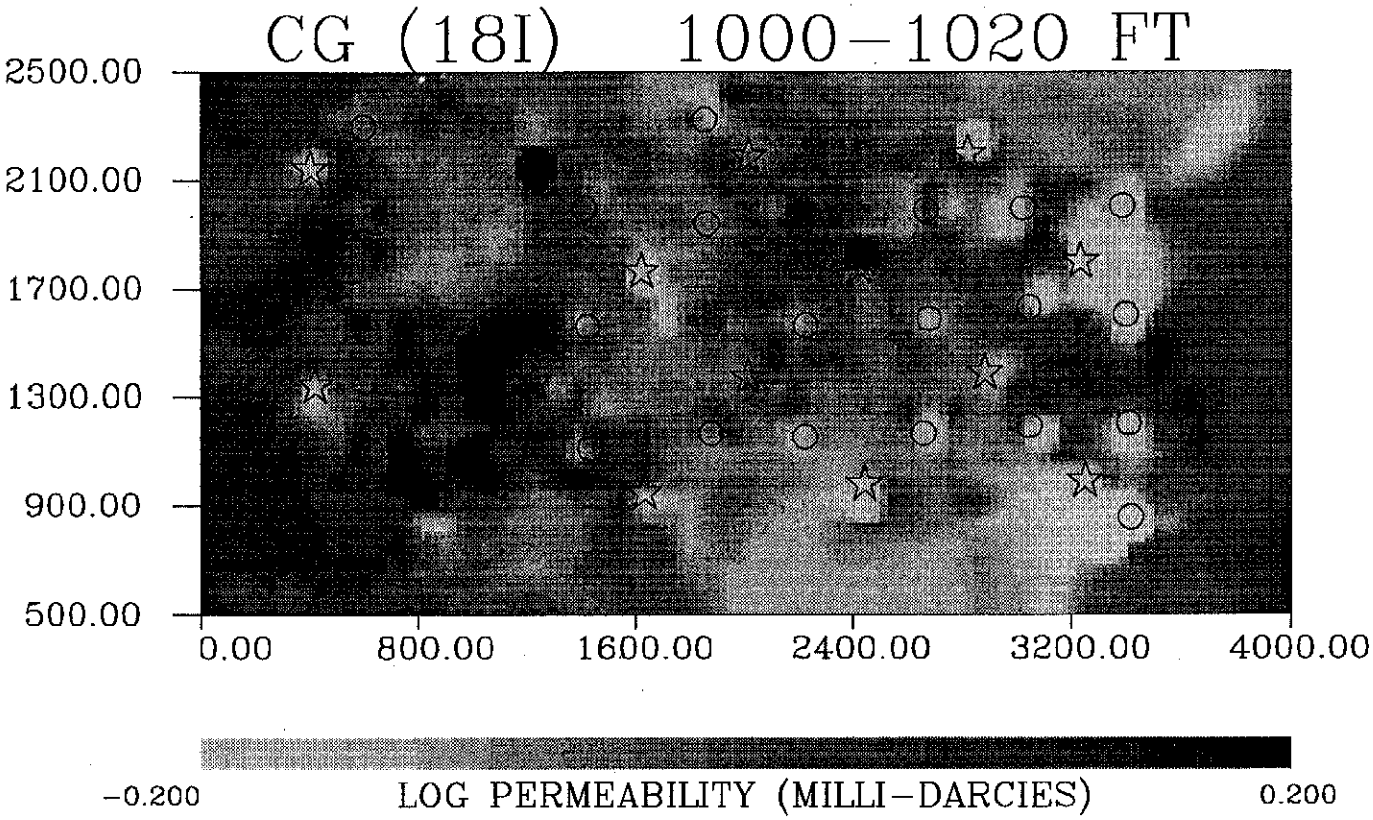


Figure 13 Permeability variation from inversion for the top layer of the North Robertson waterflood experiment.